

Current Overview of Cyclic Steam Injection Process

Johannes Alvarez^{*1}, Sungyun Han^{*2}

^{*}Co-first authors are listed in alphabetical order.

^{1,2}Texas A&M University, Department of Petroleum Engineering, College Station, Texas, 77843, USA

¹johannes.alvarez@pe.tamu.edu; ²sungyun.han@pe.tamu.edu

Abstract

Cyclic Steam Injection (CSI) is an effective thermal recovery process, in which, several driving mechanisms define the success of the process; i.e. viscosity reduction, wettability alteration, gas expansion, etc. This process was first applied in late 1950s. Then, it has been applied world-wide successfully to both light and heavy oil reservoirs. To increase the effectiveness of CSI, process was varied by chemical addition to steam, application of horizontal wells and introduction of hydraulic fracturing. With these modern technologies, average 15% of recovery factor of conventional CSI producers back in 1980's boosted up to approximately 40%. The method is attractive because it gives quick payout at relatively high success rate due to cumulative field development experiences. However, this is still uncompetitive in terms of ultimate recovery factor compared to that of other steam drive methods such as steam flooding (50-60% OOIP) or SAGD (60-70% OOIP).

Recent studies related to the CSI have focused on either the optimization of chemical additives and fracture design or questioning on geomechanical solutions to poroelastic effects. In addition, most papers discuss about follow-up process posterior to CSI such as in-situ combustion, CO₂ injection and steam flooding. This study is oriented to overview of the past and current status of CSI process in technical aspects with discussion of commercial cases throughout the world. A summarized review is given on the potential importance of encouragement of further investigation of Cyclic Steam Injection.

Keywords

Cyclic Steam Injection; Cyclic Steam Stimulation; Huff n' Puff; Thermal Enhanced Oil Recovery

Introduction

Cyclic Steam Injection, also called Huff n' Puff, is a thermal recovery method which involves periodical injection of steam with purpose of heating the reservoir near wellbore, in which, one well is used as both injector and producer, and a cycle consisting of 3 stages, injection, soaking and production, repeats to enhance the oil production rate as shown in Fig. 1.

Steam is injected into the well for certain period of time to heat the oil in the surrounding reservoir to a temperature at which it flows (200-300°C under 1 MPa of injection pressure). When enough amount of steam has been injected, the well is shut down and the steam is left to soak for some time no more than few days. This stage is called soaking stage. The reservoir is heated by steam, consequently oil viscosity decreases. The well is opened and production stage is triggered by natural flow at first and then by artificial lift. The reservoir temperature reverts to the level at which oil flow rate reduces. Then, another cycle is repeated until the production reaches an economically determined level.

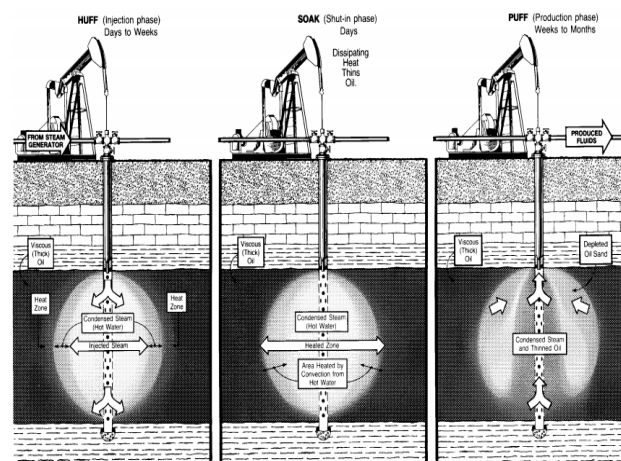


FIG. 1 CYCLIC STEAM INJECTION PROCESS (FROM UNITED STATES DEPARTMENT OF ENERGY, WASHINGTON DC.)

Typical CSI process is well suited for the formation thickness greater than 30 ft and depth of reservoir less than 3000 ft with high porosity (>0.3) and oil saturation greater than 40%. Near-wellbore geology is critical in CSI for steam distribution as well as capture of the mobilized oil. Unconsolidated sand with low clay content is favorable. Above 10 API gravity and viscosity of oil between 1000 to 4000 cp is considerable while permeability should be at least 100 md (Thomas, 2008; and Speight, 2007).

Underlying Technology

CSI includes three stages; injection, soaking and production, which are repeated until the oil production turns uneconomic (Prats, 1985, and Thomas, 2008). Application of CSI, like other EOR methods, targets to reduce the formation residual oil saturation by several driving mechanisms: viscosity reduction, changes in wettability and thermal and solution gas expansion (Prats, 1978) which depend on reservoir rock and fluid properties. For instance, viscosity reduction can be explained by mobility ratio which is the ratio of effective permeability to viscosity.

In addition, during CSI many chemical reactions occur which mainly form gaseous components such as carbon dioxide, hydrogen sulfide, and hydrogen during steam injection (Hongfu et al., 2002); and these reactions include decarboxylation of the crude, formation of H₂S from sulfur in the crude, formation of H₂, CO, CH₄ and CO₂ from reactions between water and crude and formation of CO₂ by decomposition and reactions of carbonates minerals (Prats, 1985).

The produced gases formed during the CSI create additional driving mechanism which can be named as gas drive. Also, these visbreaking reactions reduce the oil viscosity by increasing the oil mobility (Pahlavan et al., 1995, Hongfu et al., 2002, and Prats, 1985). Hongfu et al., in 2002 reported a reduction of heavy oil viscosity between 28 and 42% after CSI.

Reservoir Properties Changes with CSI

Every stimulation that is performed in the reservoir has consequences; introducing heat into the formation by CSI produces stress and deformation in oil sand formations. The resulting pore volume changes affect the reservoir permeability and consequently water mobility. Scott et al., in 1994, claimed that the volume and permeability changes are the results of three effects: change in the mean principal effective stress, change in the shear stress and change in temperature. The increase in temperature causes thermal expansion of the sand grains and sand structure. In addition, studies conducted in Cold Lake field in Canada concluded that, during steam injection, the increase of pore pressure decreases the effective confining stress and causes an unloading of the reservoir (Scott et al., 1994).

In the Clearwater formation in Canada, the effects of the volumetric expansion, during CSI, were transferred to the reservoir surrounding and the surface (Walters et al., 2000). This is sometimes

observed as small elevations of the surface near the well, usually in shallow reservoirs. In addition, Walters et al., 2002 explained pressure changes in an isolated aquifer overlying the Clearwater formation as the result of poroelastic effects during CSI. However, these geomechanical deformations and failure mechanisms produced by CSI give the initial injectivity required for steam injection and the drive energy needed for the oil production (Yuan et al., 2011).

CSI, due to the injection of a hot fluid into the formation, causes shear dilation (Wong et al., 2001). Hence, the pore rock characteristics change by means of enlarging their volume. This increases permeability which affects directly steam and hydrocarbon movements in the reservoir. Wong et al., developed a model that provided a quantitative estimation of the permeability changes caused by shear dilation.

Yale et al. affirmed that the most significant impact of dilation due to CSI is an increase in the permeability to water. This increase of the pore space is caused dilatation and mobility of the injected fluid. Further, condensation of hot water from steam ahead of the steam front pressurized the reservoir (Yale et al., 2010). Moreover, CSI induced displacements in the reservoir due to dilation and the recovery of these original conditions during production operations is a point of supply of reservoir drive energy.

Gronseth, in 1989, studied the distribution of the injected fluids during CSI in the Clearwater formation, and found that if the injection rates are faster than diffusion rates into the matrix, the reservoir volume increases to adjust the volume of the injected fluid. This volume increase is translated into a pressure increase. Later, during production, reservoir pressure reduces and effective stresses increases, so the reservoir contracts and a portion, but not the entire increased reservoir volume, is recovered (Gronseth, 1989).

There are techniques used to monitor reservoir deformation. These measures are important to optimize production and design parameters such as well length, well spacing, injection rate, cycle time, among others. In CSI, inclinometers and tilt-meters, based on surface deformation, are used to monitor steam migration and formation dilation (Du et al., 2005). However, tilt-meters are more accurate than inclinometers by more than one order of magnitude (Dusseault et al., 2002).

History: Commercial Cases

CSI was first used fortuitously in Venezuela in 1959. By that time, one of the steam injector wells began to produce, after a blowout, in much better conditions than the surrounding production wells (Trebolle and Chalot, 1993). Since then, this method has been applied in many fields such as Bolivar Coastal and Santa Barbara in Venezuela (Valera et al., 1999), Cold Lake Oil Sands in Canada, Xinjiang and Liaohe in China (Liguo et al., 2012), Midway-sunset in California (Jones et al., 1990), among other heavy oil fields.

At the early stages of CSI application, CSI was considered as an old-school oil production method in which operations are ahead of research developments (Ramey et al., 1969). The literature shows that many publications, explaining CSI processes, were based on field experiences rather than research work. There are a lot of unknowns about the process parameters such as the number of stimulation cycles, well orientation and number of wells, operating condition, the increase of water cut, among others. Therefore, on early CSI field applications, the process was performed as trial-and-error field-scale experiment (Ramey, 1967). After many research studies and field experiences, important technology problems were reduced.

First, the number of stimulation cycles increased by time. By 1974, CSI has an average of three stimulation cycles with a maximum reported of 22 (Ali et al., 1974). In 1990, in the Midway-Sunset field, California, there was already a well with 39 cycles. Also, out of 1500 wells, there were 75 wells with more than 30 cycles, and 350 wells with more than 20 cycles (Jones et al., 1990). This increment in the number of cycles was accomplished by getting better understanding of steam properties, reservoir characteristics, and injection conditions.

Second, well orientation and number of wells were improving by time. In Trinidad and Tobago, slim-hole injectors, insulated tubing and packers, and limited entry perforations have been used to combat gravity segregation consequences (Khan, 1992). As well, steam was injected with foam-diverting agents to control water breakthrough resulting from high injectivity.

In addition, in the Cold Lake oil sands, Canada, steam distribution in horizontal wells was improved by using screen sections, which facilitated contact between the well and the reservoir. Also, inside these

screen sections, small flow orifices were used to control the flow between the inner pipe and the reservoir to enhance oil production and reduce steam consumption (Oil and Gas Journal report by Bob Tippee, 2012).

In China, the most up to date methods and techniques used in CSI include: high-efficient steam injection by automatic controlling steam generation, insulating surface pipeline and multi-zone steam injection; as well as artificial lifting, sand control, CSI with chemical additives, re-entry drilling technology, and process control systems (Haiyan et al., 2005). In addition, steam distribution has been improved by using separated-zone steam injection techniques such as selected, dual and multi zone injection, either sequentially or simultaneously. This method showed, in field testing to 76 wells of the Liaohe oil field, an increase up to 70% of the steam zone (Liguo et al., 2012). Moreover, as well in horizontal well, the tubing and annulus of the same well have been applied to inject to in the toe and heel separately (Liguo et al., 2012).

Third, operating conditions of pressure and temperature have adjusted to each case based on reservoir properties and well design. In the Cold Lake field, CSI has been achieved by injection at pressures high enough to fracture the formation (Beattie et al., 1991). In California, specifically in Potter sands in the Midway-Sunset field, a sequential steaming process was implemented. This approach involved heating the reservoir rather than heating each well separately (Jones et al., 1990). The wells were stimulated in rows from down to up dip of the reservoir. Using this methodology, the production per well increased up to a rate of 30% per year (Jones et al., 1990).

Another technique, in pilot stage and successfully simulated, is the use of Top-Injection Bottom-Production (TINBOP) whose principle is to inject steam at the top of the reservoir using the short well string and produced from the bottom of the reservoir using the long well string. (Morlot et al., 2007). Simulation studies, conducted by Morlot et al. showed TINBOP increased oil recovery by 57 to 93%, compared to conventional CSI (Morlot et al., 2007). One feature of this method is that there is no soaking period.

Fourth, the increase of water cut is also addressed. In CSI, each succeeding cycle normally increases water cuts (Ali et al., 1974). Consequently, in the late 70's there was a trend to convert these operations into

steam drives due to the decrement in oil recovery (Prats, 1978). This trend has changed in the last years with the use of chemical additives on CSI.

Recently, there have been important progresses in oil recovery using chemical addition. Although CSI increases oil recovery, chemical addition with CSI increases it even further (Ramey et al., 1967). Nowadays, in CSI processes, co-injection of steam with gels, foams, and surfactants, among other chemicals, are used to increase oil production and reduce water production. In Russia, specifically in the Permian-Carboniferous reservoirs of the Usinsk field, gels and foams have been injected with CSI from 2007 to 2011, and an increase of 20-30% oil rate and decreased 33-35% water cut (Taraskin et al., 2012) have been observed.

In Canada, Liquid Addition to Steam for Enhancing Recovery (LASER) has been field-tested for a single cycle at Cold Lake field. Previous work indicated that, if successful, the LASER process could increase the recovery factor by 3 – 6% OOIP (Leaute et al., 2007).

Similarly in Canada, other processes have been tested to increase CSI performance such as air injection, achieving 15% incremental in addition to the 12-20% recovery with high pressure CSI (Jiang et al., 2010), and biodiesel and carbamide injection (Babadagli et al., 2010 and Zhang et al., 2009), both used as surfactants to enhance the CSI efficiency.

The field tests in Henan Oil Field, China, using carbamide increased oil recovery by 7% and decreased Residual Oil Saturation (SOR) almost by 1% (Zhang et al., 2009). As well, in the Bachaquero field in Venezuela, an ionic-alkyl-aryl sulfonate surfactant (LAAS) has been used to generate foams that enhance steam distribution more evenly in the reservoir by restricting steam to the areas with higher permeability. This technique has improved the production per cycle from 15 to 40% (Valera et al., 1999). Moreover, solvents have been used to improve steam injectivity by removing organic deposits from the rock and changing its wettability in Costa Bolivar, Zulua, Venezuela (Mendez et al., 1992).

Finally, wettability changes in CSI due to temperature increase have been studied by several authors with different results. On one hand, there is a line of thought which assures that as temperature increases, the system oil-water-rock becomes more water-wet (Prats, 1985, Schembre et al., 2006, Kovscek et al., 2008, and Poston et al., 1970). On the other hand, another

tendency advocates that the system becomes more oil-wet as temperature increases (Rao and Karyampudi, 1999, Escrochi et al., 2008, and Rao, 1999); also, there is a third line of thought explaining that wettability is independent of temperature changes (Miller and Ramey, 1985, and Polkar et al., 1989).

Studies with Diatomaceous rocks and Berea sandstones conducted by Schembre et al., 2006, showed that both diatomaceous and Berea cores become more water-wet as temperature increases (from 100 to 200°C). This behavior was attributed to fines detachment, in low salinity and high pH steam condensate fluid, which stabilizes a thin water film that covers the rock surface avoiding contact with the oil phase. This fines detachment depends on temperature and mineralogy; for example, wettability changes are reached faster in silica than that in clays (Schembre et al., 2006). In addition, Poston et al., 1970, conducted similar studies using unconsolidated sands from Houston sands and Midway-Sunset field, California, reaching the conclusion that increasing temperature (from 25 to 150°C) is determined in improving water-wetness in the unconsolidated sands.

On the other hand, Rao and Karyampudi, 1999, and Rao, 1999, conducted CSI lab and field test in the heavy oil and bitumen Elk Point Cummings formation, Canada. Their results showed that at high temperatures (162 to 196°C), the formation, which is mainly silica (87%), became oil-wet. Moreover, they also discover that salt deposition, mainly calcium carbonate (CaCO_3), in one of the core layers prevented oil-wet behavior at high temperatures, changing the wettability to water-wet. This effect was proved in core flooding and field test in which increment in oil rate and decrement in water cut were observed (from 22 BPD and 83% in the fourth cycle to 51 BPD and 77% in the five cycle) (Rao and Karyampudi, 1999).

Wettability reversal effect at high temperatures is also attributed to asphaltene precipitation. Using Athabasca bitumen and live oil sample with 5% and 3.17% asphaltene respectively, Escrochi et al., 2008, showed that from 150 to 400 °C the system shifted to oil-wet until asphaltene precipitation was completed and then wettability was changed to water-wet.

Moreover, in the literature, results showed that temperature do not impact wettability during CSI, and Miller and Ramey, 1985 tested the unconsolidated Ottawa Silica Sand and a consolidated Berea Sandstone with temperatures from 25 to 150° C, concluding that there were not changes in residual

saturations that imply variance in wettability. The same results were reached in the unconsolidated silica sands at 125 to 175 °C by Pollkar et al., 1989.

Consequently, when CSI is applied, there are different positions in describing wettability mechanism and their changes with temperature. However, it is important to point out that these results mainly depend on the chemical properties of fluids injected, asphaltene content and the mineralogy of the reservoir.

From its early stages until today, CSI has evolved significantly from a process discovered by chance where trial and error governed the operations with little number of cycles and low recovery factor to state-of-the-art applications with a great variety of chemical additives and well geometries which increase the number of cycles and the ultimate oil recovery. However, more research needs to be done in evaluating wettability changes at field scale to determine the factors that influence early water break and reduce oil production at different mineralogy and injection temperatures.

Current State-of-the-art: Applications

The method is quite effective, especially in the first few cycles providing quick payout. However, ultimate recovery by cyclic steam injection is low (10-40% of Original Oil in Place, OOIP), compared to that of steam flooding and Steam Assisted Gravity Drainage (SAGD) which are over 50% of OOIP (Thomas, 2008; Speight, 2007; Xia and Greaves, 2006) as shown in TABLE. 1. Therefore, it is quite common for wells to be produced in the cyclic steam manner for a few cycles before put on a steam flooding regime with other wells (Alikhlalov et al., 2011).

TABLE 1 OIL RECOVERY RATE OF THERMAL EOR METHODS

Oil Recovery Factors (successful projects)	
Thermal EOR	% of OOIP
CSI	10 - 40
Steam flooding	50 - 60
SAGD	60 - 70
In-situ Combustion*	70 - 80

*In-situ Combustion using THAI—'Toe-to-Heel Air Injection'

Conventional CSI process usually has average recovery factor lower than 20%. However, this can be doubled with combination of unconventional technologies which have become profitable including

co-injection of steam with chemical additives, directional drilling, and hydraulic fracturing. Recently, technical aspects like injected steam/produced oil ratio, presence of water cut in the producing well and excessive heat losses have required special attention. Many literatures have presented studies on these areas at laboratory scale (i.e, Castro et al., 2010). Investigations have been optimizing the cyclic steam injection technology by chemical addition to the steam. Currently, the performance of CSI is enhanced by co-injection of steam with chemicals such as surfactants, solvents, miscible and immiscible gases.

CSI with Chemical Additives

Since 1960, investigations on cyclic steam injection technology have been conducted to improve recovery factor by adding chemical additives to steam, fracturing, and placing horizontal wells for different types of reservoir. In the reservoir, the chemical additives enhance the production by increasing the mobility of oil and enabling condensed water to carry higher loading of oil. Numerous studies on chemical additives to steam have been conducted to affect heavy oil properties favorably such as solvents, surfactants, miscible and immiscible gases.

1) Solvents

The idea of adding solvents to the steam to reduce the oil viscosity has been reported in the literature since 1970s. Previously, solvents and light crudes had been used as diluents to optimize pumping and pipeline transportation of heavy crudes. Both laboratory and field tests later years proved that the use of solvent as an additive to steam during in-situ recovery improved the mobility ratio of displacing and displaced fluid and sweep efficiency. The mechanism is following: the vaporized solvent is co-injected with steam and travels with the steam front. It condenses and mixes with the oil in the cooler regions of reservoir creating a transition zone of lower-viscosity fluid between steam and oil. Consequently, the mobility ratio between steam and oil increases, resulting in higher production rate.

The success of process depends on the solvent type, treatment size and the solvent placement. It was concluded that the use of small quantities of medium volatile solvent (no more than 10% of steam volume) creates the best effectiveness in increasing total oil production (Shu and Hartman, 1988). In many of the previous researches, naphtha

was employed quite frequently which was found to be highly effective in opening a steam flow path due to its high volatility. Other solvents that were used in recent researches include CO₂, ethane, and a mixture of gases (Yongtao et al., 2011), kerosene, and even some effluents from some refinery processes (Castro et al., 2010).

2) Surfactants

Although adding solvents to steam can increase production recovery up to 30% upon earlier cycles, high injection volumes are required to reduce the viscosity of oil appreciably thereby necessitating solvent recovery, which leads to high operational costs. Therefore, adding surfactants to injected steam to reduce oil-water interfacial tension and alter wettability and therefore increase recovery was introduced. Most widely used agent is called Thin Film Spreading Agents (TFSA). TFSA compounds reduce interfacial tension by the application of a spreading film strong enough to overcome the emulsifying agents naturally found between the oil-water and oil-rock interfaces. By reduction of the interfacial energies between the oil-rock and water-rock, water wetting of the rock results, leading to the release of oil particles from the rock surface improving oil mobility (Adkins et al., 1983). Successful field applications of TFSA in California and Alberta were reported with indication of significant improvement in heavy oil recovery factor up to 20% (Srivastava and Castro, 2011).

The capability of the steam-surfactant mixture to divert steam entry into the sands varies directly with the concentration of the surfactant present, steam quality and the addition of a non-condensable gas. Some pilot tests in Bolivar Coast, Venezuela, reported the optimum level of surfactant concentration in the steam liquid phase 1 to 1.3 % (Robaina et al., 1988) above which no additional diversion was obtained. Most conventional surfactant injection projects, steam quality maintained averagely 60 to 70% (Blair et al 1982; Adkins et al., 1983). Co-injections of more efficient surfactants were also tested; however, they required high steam quality as 80 to 90%, which causes higher operating costs. Srivastava and Castro reported that TFSA requires only small amount of concentration (250 ppm) while sustaining steam quality as below 70% (Srivastava and Castro, 2011). Additionally, some laboratory

tests demonstrated that introducing non-condensable gases (i.e nitrogen) helps to stabilize the foam, affording greater plugging of the porous media consequently (Robaina et al., 1988).

CSI with Horizontal Well

Due to the presence of certain sand volumes at the bottom of the reservoir which is not recoverable by using vertical wells, the idea of horizontal well was introduced to the CSI process. The main advantages of the horizontal wells are improved sweep efficiency, increased producible reserves as well as steam injectivity, and decreased number of well required for field development (Joshi, 1991). Although most of simulation studies proved notable advantages of horizontal well over vertical well (Adegbesan 1992, and Chang et al., 2009), CSI with horizontal well had little success in fields before 2000s. The main reason was the extra operating costs which were double that of vertical wells back then. Other factors include geological/reservoir characteristics and operational aspects such as uneven steam distribution and sand productions. For example, the activity of horizontal drilling in Bachaquero field in Venezuela where high oil viscosity (~18000 cp) encountered did not appear profitable, causing a low annular fluid level (Mendoza et al., 1997). A simulation study later on also showed that the application of horizontal well in same field was not economically attractive (Escobar et al., 2000).

On the other hand, few pilot tests in early 2000s had success on horizontal well application; and indeed, those horizontal producers in comparison to typical vertical ones in each area improved production performance and thermal efficiency as well as operating costs. Representative pilots are in South Midway-Sunset field (McKay et al., 2003) and Cymric/McKittrick field in California (Cline et al., 2002). Both fields showed about 20 to 50% improvement in production over results from vertical wells and benefited from maximum 45% of directional drilling cost reduction relative to that of a decade ago.

Despite the reduced drilling costs, operating costs for generating steam still remains high due to greater heat loss when steam injection is schemed to horizontal well application. Further investigations inquire possibilities to address the solutions to this problem. Chang et al., examined in his simulation study the co-injection with solvent (n-hexane C₆H₁₄) and alternate solvent/steam cycles to reduce total number of cycles. (Chang et al., 2009).

CSI with Hydraulic Fracturing

The idea of combining cyclic steam stimulation with hydraulic fracturing came out when both steam injection and completion (i.e, sand control completion) techniques generated potential formation damage thus, the permeability near the wellbore creating a choke was lowered that further reduces the oil mobility. Creating fractures allows a more efficient placement of injected steam, heating up larger volume of reservoir and reducing residual oil saturation. This combination is usually considered for low-permeability heavy oil reservoirs like California diatomite (0.1-0.5 md) or Athabasca oil sands (~2.5 d). Several studies reported desirable results (Manrique et al., 1996, and Settari et al., 1981).

Fines and sand production problems are found commonly during cyclic steam injection. The recent study investigated the efficiency of fracturing with viscoelastic surfactant fluid instead of water which worsens the sand and fine production. It was concluded that anionic surfactant fluids minimize gel damage and maintain favourable proppant transportation (Gomez et al., 2012).

Follow Up Methods: Post CSI

CSI is widely used in oil recovery due to its quick response; however, recovery factors are relatively low (10-40% OOIP) compared to other thermal methods such as steam flooding (50-60% OOIP) or in-situ combustion (70-80% OOIP) (Thomas, 2008). This is because the natural energy of the reservoir, as well as oil production, decreases and, when several cycles are reached, oil production tends to decrease even more with decreasing pressure and increasing water production. Consequently, some follow-up processes are used after the implementation of CSI to improve oil recovery, such as CO₂ injection (Luo et al., 2005), steam flooding (Yang, 2007), and air injection as in-situ combustion (Gates et al., 2011, and Hajdo et al., 1985), among others.

One example of CO₂ injection after CSI is in the Lengjiabao heavy oil reservoir, in which CO₂ was injected in extra heavy oil (10,000 -50,000 mPa.s at 50°C) after 3 cycles of CSI with satisfactory results; increasing oil mobility with CO₂ utilization ratio from 3.0 to 6.0 tons oil /tons CO₂ and oil recovery from 10 to 35% (Luo et al., 2005). However, in other wells tested with low permeability, porosity and oil saturation, the injection of CO₂ did not increase oil production.

Another thermal method frequently used as a follow up process for CSI is steam flooding. One of the experiences reported was in the Guantao formation (porosity and permeability relatively high and extra heavy oil with viscosities of 230,000 mPa.s at 50°C) in the Liaohe Oil Field, China, where CSI was applied previously. Steam flooding was adapted by using horizontal wells placed between current vertical CSI wells (Yang, 2007). These vertical wells produced for 3 cycles by CSI and then some of them were switched to steam flood as soon as the horizontal-vertical wells communication was identified. Yang in 2007 reported that the wells have been producing since February 2005 by steam flooding favored by gravity drainage forces. Initially, the predicted oil recovery by CSI was 29% of OOIP, and, with steam flooding follow up after CSS, the forecasted oil recovery was 56% (Yang, 2007).

However, steam flooding is not the right recipe as follow-up after CSI for all types of formations. Every reservoir has its own characteristics such as vertical and horizontal permeabilities, reservoir properties changes caused by CSI, reservoir thickness, and viscosity of the fluids, among others, which have to be evaluated before steam flooding is implemented after CSI (He et al., 1995).

In the Bachaquero-01 reservoir in western Venezuela, CSI has been used since 1965 and currently the production wells have more than 6 cycles. An Extended Cyclic Steam Injection, which is a combination of steam injection and steam flooding, was evaluated numerically. The prediction cases were simulated for 7 cycles of 14 months each and approximately 9 months of steam flooding in different well patterns (Chourio et al., 2011). The simulated results showed that there was an additional recovery of 3.7%, reaching the highest recovery in the area of 24.3% of OOIP (Chourio et al., 2011). The pilot test for this project was planned in 2012.

Finally, in-situ combustion performance has also been numerically investigated as a follow up process for CSI (Gates et al., 2011). In Canada, in the Margarite Lake, in wells with a depth of 1476 feet and thickness of 112 feet (Hajdo et al., 1985) and Morgan Field, with wells with a depth of 670 feet and thickness of 30 feet (Marjerrison and Fassihi, 1995), air injection pilots were performed after CSI and the process were proved to be successful (Gates et al., 2011, Hajdo et al., 1985 and Marjerrison and Fassihi, 1995). In addition, CSI was implemented in the Cold Lake oil sands, and the oil recovery was recorded to be 15-20% of the

OOIP (Nzekwu et al., 1990). Consequently, an in-situ combustion process was implemented. The results, presented by Nzekwu et al. showed that the average reservoir temperature and heated zone increased after in-situ combustion which consequently would increase oil recovery. In addition, in the heavy oil reservoir of Midway Field in California, a successful in-situ combustion pilot was conducted in a section subjected to CSI for seven years (Counihan, 1977). The previous CSI cycles helped injectors to prevent burnout, clean the perforations and reduce spontaneous ignition.

Currently, the most used follow up process after CSI is steam flooding. One reason is because it utilizes the installed equipment into the well and on surface which reduces capital cost. However, the most important ground is due to its attribute to sweep the remaining oil to a specific production well. Moreover, CO₂ flooding has been proved to be successful in limited areas and further research must be done to fully develop this technique; likewise, initial investment and CO₂ utilization affects directly capital cost. Finally, air injection has been efficient in some places as well, but it is a process very complicated for simulation and field tested.

Conclusions

- CSI has improved since its discovery in 1959, little number of cycles and low recovery factor have been increased by the use of chemical additives and by better understanding of the geometry and mineralogy of the wells. However, more research needs to be done in understanding relative permeability and wettability changes with temperature at field scale in different formations to increase ultimate oil recovery.
- Cyclic Steam Injection combined with unconventional technologies such as co-injection with chemical additives, horizontal drilling and hydraulic fracturing have been highly successful, improving its conventional recovery factor up to 40%. Recent studies showed that this can be increased even higher.
- Cyclic Steam Injection with horizontal well has had considerable success thanks to reduced directional drilling cost and improved sweep efficiency, although further economic evaluations need to be considered.
- CSI with Hydraulic fracturing has shown good results for low-permeability formation. Further

investigation on fracturing fluid needs to be acquired to solve sand productions during the operation.

- In many cases, follow up processes after CSI are convenient solutions to increase reservoir ultimate recovery. However, these processes must be evaluated carefully considering reservoir properties and mineralogy and fluid interaction before fully implemented. In addition, in follow up process selection, economic viability is a major issue, so the increase in oil recovery must be sufficient to cover capital cost and maintain the project profitable during the forecasted time.

ACKNOWLEDGMENT

The authors would like to thank Dr. Berna Hascakir for her guidance and encouragement to write this paper.

REFERENCES

- Adegbesan, K. G. (1992). "Reservoir Simulation Study of a Thermal Horizontal Well Pilot in the Cold Lake Oil Sands." SPE Reservoir Engineering 7(4): 403-406.
- Adkins, J. D. (1983). "Field Results of Adding Surfactant to Cyclic Steam Wells." SPE Annual Technical Conference and Exhibition. San Francisco, California, Society of Petroleum Engineers.
- Ahmed, Tarek, D., Meehan, and Nathan. (2012). "Advanced Reservoir Management and Engineering (Second Edition)." Pages 541-585.
- Ali, Farouq S. M. (1974). "Current Status of Steam Injection as a Heavy Oil Recovery Method." Journal of Canadian Petroleum Technology. Volume 13, Number 1.
- Alikhlalov, K. and Dindoruk B. (2011). "Conversion of Cyclic Steam Injection to Continuous Steam Injection." SPE Annual Technical Conference and Exhibition. Denver, Colorado, USA, Society of Petroleum Engineers.
- Babadagli, T., Er, V., Naderi, K., Burkus, Z., and Ozum, B. (2010). "Use of Biodiesel as an Additive in Thermal Recovery of Heavy Oil and Bitumen." Journal of Canadian Petroleum Technology. Volume 49, Number 11.
- Beattie, C.I., Boberg, T.C., and McNab, G.S. (1991). "Reservoir Simulation of Cyclic Steam Stimulation in the Cold Lake Oil Sands." SPE Reservoir Engineering. Volume 6, Number 2.

- Blair Jr., C. M., Scribner, R. E., and Stout, C. A. (1982). "Chemical Enhancement of Oil Production by Cyclic Steam Injection." *Journal of Petroleum Technology* 34 (12): 2757-2762.
- Castro, Y. E., Veliz, A. M., Sanchez, D. A., Rodriguez, M. M., Rondon, N. G., Rivero, S., and Cortez, M.L. (2010). "Cyclic Steam Injection with Solvents as Method of Thermal Recovery for Heavy and Extraheavy Oils: Laboratory Tests." *Canadian Unconventional Resources and International Petroleum Conference*. Calgary, Alberta, Canada, Society of Petroleum Engineers.
- Chang, J., Ivory, J., and Rajan, R. S. V. (2009). "Cyclic Steam-Solvent Stimulation Using Horizontal Wells." *Canadian International Petroleum Conference*. Calgary, Alberta, Petroleum Society of Canada.
- Chourio, Geragg; Bracho, Jose and Mohtad, Mehrdad. (2011). "Evaluation and Application of the Extended Cyclic Steam Injection as a New Concept for Bachaquero-01 Reservoir in West Venezuela." *SPE 148083-MS*.
- Cline, V. J. and M. Basham. (2002). "Improving Project Performance in a Heavy Oil Horizontal Well Project in the San Joaquin Valley, California." *SPE International Thermal Operations and Heavy Oil Symposium and International Horizontal Well Technology Conference*. Calgary, Alberta, Canada.
- Counihan, and Thomas M. A. (1977). "Successful In-Situ Combustion Pilot in the Midway-Sunset Field, California." *SPE 6525-MS*.
- Du, J., Brissenden, S.J., McGillivray, P., Bourne, S., Hofstra, P., and Davis, E.J., Roadarmel, W.H., Wolhart, S.L., Marsic, S., Gusek, and R., Wright, C.A. (2005). "Mapping Reservoir Volume Changes During Cyclic Steam Stimulation Using Tiltmeter Based Surface Deformation Measurements." *SPE 97848-MS*.
- Dusseault, M.B. and Rothenburg, L. (2002). "Analysis of Deformation Measurements for Reservoir Management." *Oil & Gas Science and Technology – Rev. IFP*, Vol. 57. No. 5, pp. 539-554.
- Escobar, E., Valko, P., Lee, W. J., and Rodriguez, M.G. (2000). "Optimization Methodology for Cyclic Steam Injection with Horizontal Wells." *SPE/CIM International Conference on Horizontal Well Technology*. Calgary, Alberta, Canada.
- Escrochi, M., Nabipour, M., Ayatollahi, Sh., and Mehranbod, N. (2008). "Wettability Alteration at Elevated Temperatures: The Consequenses of Asphaltene Precipitation." *2008 SPE International Symposium and Exhibition on Formation Damage held in Lafayette, Luisiana, USA*. SPE 112428.
- Gates, Ian D. and Wang, Jacky. (2011). "Evolution of In Situ Oil Sands Recovery Technology in the Field: What Happened and What's New?" *SPE 150686-MS*.
- Gomez, J., Morales, H., Toyo, D., and Bracho, J. (2012). "Fracturing With Viscoelastic Surfactant Fluid in Cyclic Steam Injection Wells - A Synergy for Heavy Oil Recovery." *SPE 153536-MS*.
- Gronseth, J.M. (1989). "Geomechanics Monitoring of Cyclic Steam Stimulation Operations In the Clearwater Formation." *International Society for Rock Mechanics IS-1989-166*.
- Haiyan, H., Shuhong, W., Yitang, Z., Dingmin, W., and Zhong, G. (2005). "State-of-the-Art of Heavy-Oil Development in China and Its Technology Challenges." *SPE 10617-MS*.
- Hajdo, L.E., Hallam, R.J., and Vorndran. (1985). "Hydrogen Generation During In-Situ Combustion." *SPE 13661-MS*.
- He, Z., Zhang, R., Pu, H. Y., and Ren, X. (1995). "The Feasible Conditions Study of Steamflooding for Heavy Oil Reservoirs In China After Cyclic Steam Injection." *SPE 30303-MS*.
- Hongfu, F., Yongjian, L., Liying, S., and Xiaofei, Z. (2002). "The Study on Composition Changes of Heavy oils during Steam Stimulation Processes." *ELSEVIER. Fuel* 81. p.p 1733-1738 .
- Jiang, Q., Thornton, B., Russel-Houston, J., and Spence, S. (2010). "Review of Thermal Recovery Technologies for the Clearwater and Lower Grand Rapids Formations in the Cold Lake Area in Alberta." *Journal of Canadian Petroleum Technology*. Volume 49, Number 9.
- Jones, Jeff and Cawthon, Gary J. (1990). "Sequential Steam: An Engineered Cyclic Steaming Method." *Journal of Petroleum Technology*. Volume 42, Number 7.
- Joshi, S. D. (1991). "Thermal Oil Recovery With Horizontal Wells (includes associated papers 24403 and 24957)." *Journal of Petroleum Technology* 43(11): 1302-1304.

- Khan, Jamaludin and Parag, Dhanpaul. (1992). "Twenty-Five Years of Oil Recovery by Steam Injection." SPE 24198-MS.
- Kovscek, A.R., Schembre, J.M. and Tang, G.-Q. (2008). "Authors' Reply to Discussion of Interrelationship of Temperature and Wettability on the Relative Permeability of Heavy Oil in Diatomaceous Rocks." SPE Reservoir Evaluation & Engineering. Volume 11, Number 3. p.p. 437-438.
- Leaute, R. P. and Carey, B. S. (2007). "Liquid Addition to Steam for Enhancing Recovery (LASER) of Bitumen with CSS: Results from the First Pilot Cycle." Journal of Canadian Petroleum Technology. Volume 46, Number 9.
- Liguo, Zhong; Shoujun, Zhang; Fei, Wu; Baoshan, Lang; Heng, Liu and Shuai, Gai. (2012). "Improved Heavy-Oil Recovery by Separated-Zones Horizontal-Well Steam Stimulation." Journal of Canadian Petroleum Technology. Volume 51, Number 2.
- Luo, R., Cheng, L.-S., and Peng, J.-C. (2005). "Feasibility Study of CO₂ Injection for Heavy Oil Reservoir after Cyclic Steam Stimulation: Liaohe oilfield test." SPE 97462-MS.
- Manrique, J. F. (1996). "Optimization of Thermal Processes Through Combined Application of Horizontal Wells and Hydraulic Fracturing Technology." International Conference on Horizontal Well Technology. Calgary, Alberta, Canada, Society of Petroleum Engineers, Inc.
- Marjerrison, D.M. and Fassihi, M.R. (1995). "Morgan pressure cycling in-situ combustion project: performance and modeling." Geological Society, London, Special Publications. V.84. p. 275-286.
- McKay, C., Jones, J., Pomerene, J. (2003). "Successful Horizontal Producers in Midway-Sunset Thermal Operations." SPE Western Regional/AAPG Pacific Section Joint Meeting. Long Beach, California, Society of Petroleum Engineers.
- Mendez, Z., Alvarez, J. M., Escobar, E., Colonos, P., and Campos, P. (1992). "Cyclic Steam Injection With Additives: Laboratory and Field Test Results of Steam/Foam and Steam/Solvent Processes." SPE Annual Technical Conference and Exhibition. Washington, D.C. Society of Petroleum Engineers Inc. SPE 24632-MS
- Mendoza, H., Padron, A., and Portillo, F. (1997). "Steam Stimulation In Horizontal Wells Pilot Test In Venezuela." Annual Technical Meeting. Calgary, Alberta, Petroleum Society of Canada.
- Miller, Mark A., and Ramey Jr., H.J. (1985). "Effect of Temperature on Oil/Water Relative Permeabilities of Unconsolidated and Consolidated Sands." SPE Journal. Volume 25, Number 6. p.p. 945-953.
- Morlot, C. D. and Mamora, D. (2007). "TINBOP Cyclic Steam Injection Enhances Oil Recovery in Mature Steamfloods." Petroleum Society of Canada.
- Nzekwu, Ben I., Hallam, Richard J., and Williams, G.J.J. (1990). "Interpretation of Temperature Observations From a Cyclic-Steam/ In-Situ-Combustion Project." SPE Reservoir Engineering. Volume 5, Number 2.
- Oil and Gas Journal by Bob Tippee. (2012). "ExxonMobil licenses oil sands steam system." Houston, Feb. 2, 2012. <http://www.ogj.com/content/ogj/en/articles/2012/02/exxonmobil-licenses-oil-sands-steam-system.html>.
- Pahlavan, Hamid and Rafiqul, Islam. (1995). "Laboratory simulation of geochemical changes of heavy crude oils during thermal oil recovery." Journal of Petroleum Science and Engineering. Volume 12, Issue 3, Pages 219-231.
- Pollkar, Marcel, Puttagunta, V. R., Decastro, V., Ali, and Farouq S. M.. (1989). "Relative Permeability Curves For Bitumen And Water In Oil Sand Systems." Journal of Canadian Petroleum Technology. Volume 28, Number 1.
- Poston, S.W., Ysrael, SHossain, A.K.M.S., Montgomery III, E.F., and Ramey Jr., H.J. (1970). "The Effect of Temperature on Irreducible Water Saturation and Relative Permeability of Unconsolidated Sands." SPE Journal. Volume 10, Number 2. p.p. 171-180.
- Prats, Michael. (1978). "A Current Appraisal of Thermal Recovery." Journal of Petroleum Technology. Volume 30, Number 8.
- Prats, Michael. (1985). "Thermal Recovery." SPE Monograph Volume 7. Chapter 6. 1985.
- Ramey Jr., H. J. A. (1967). "Current Review of Oil Recovery by Steam Injection." SPE 12247.
- Ramey Jr., Henry J. (1969). "A Current Look at Thermal Recovery." SPE 2739-MS.

- Rao, Dandina N. (1999). "Wettability Effects in Thermal Recovery Operations." SPE Reservoir Eval. & Eng. Vol. 2, No. 5.
- Rao, Dandina N., and Karyampudi, R.S. (1999). "Productivity Enhancing Wettability Control Technology for Ciduc Steam Process in the Elk Point Cummings Formation." Journal of Canadian Petroleum Technology. Special Edition 1999, Volume 38, Number 13.
- Reis, J. C. (1990). "Studies of Fractures Induced During Cyclic Steam Injection." SPE California Regional Meeting. Ventura, California, Society of Petroleum Engineers Inc.
- Robaina, R. M. and J. L. Ziritt (1988). "Evaluation of a Surfactant: Steam-Soak Pilot Test in the Bolivar Coast, Venezuela." SPE Enhanced Oil Recovery Symposium. Tulsa, Oklahoma, 1988.
- Schembre, J.M., Tang, G.-Q., and Kovscek, A.R. (2006). "Interrelationship of Temperature and Wettability on the Relative Permeability of Heavy Oil in Diatomaceous Rocks (includes associated discussion and reply)." SPE Reservoir Evaluation & Engineering. Volume 9, Number 3. p.p. 239-250.
- Scott, J. D., S. Proskin, A., and Adhikary, D. P. (1994). "Volume And Permeability Changes Associated With Steam Stimulation In an Oil Sands Reservoir." Journal of Canadian Petroleum Technology. Volume 33, Number 7.
- Settari, A. and J. M. Raisbeck. (1981). "Analysis and Numerical Modeling of Hydraulic Fracturing During Cyclic Steam Stimulation in Oil Sands." Journal of Petroleum Technology 33 (11): 2201-2212.
- Shu, W. R. and K. J. Hartman. (1988). "Effect of Solvent on Steam Recovery of Heavy Oil." SPE Reservoir Engineering 3(2): 457-465.
- Speight, J. G. (2007). "The Chemistry and Technology of Petroleum." CRC Press/Taylor & Francis. 4th Edition, Volume 114, Chapter 6.
- Srivastava, P. and Castro, L. U. (2011). "Successful Field Application of Surfactant Additives to Enhance Thermal Recovery of Heavy Oil." SPE Middle East Oil and Gas Show and Conference. Manama, Bahrain, Society of Petroleum Engineers.
- Taraskin, Evgeniy; Ursegov, Stanislav; Pechor, N., Muliak, Vladimir; Chertenkov, Mikhail, and Alabushin, Andrey. (2012). "Thirty Years of Experience in the Application of Thermal Methods of Heavy Oil Recovery in the Permian-Carboniferous Reservoir of the Usinsk Field." SPE 160759-MS.
- Thomas, S. (2008). "Enhanced Oil Recovery – An Overview." Oil & Gas Science and Technology – Rev. IFP, Vol. 63. No. 1, pp. 9-19.
- Trebolle, R. L., Chalot, J. P., and Colmenares, R. (1993). "The Orinoco Heavy-Oil Belt Pilot Projects and Development Strategy." SPE International Thermal Operations Symposium. Bakersfield, California, Society of Petroleum Engineers, Inc.
- Valera, Cesar A., Escobar, Manuel A., and Iturbe, Yrene J. (1999). "Use of Surfactants in Cyclic Steam Injection in Bachaquero-01 Reservoir." SPE 54020-MS.
- Walters, D.A., Settari, A., and Kry, P.R. (2000). "Poroelastic Effects of Cyclic Steam Stimulation in the Cold Lake Reservoir." SPE 62590-MS.
- Walters, D.A., Settari, A., and Kry, P.R. (2002). "Coupled Geomechanical and Reservoir Modeling Investigating Poroelastic Effects of Cyclic Steam Stimulation in the Cold Lake Reservoir." SPE Reservoir Evaluation & Engineering. Volume 5, Number 6.
- Wong, R. C. K. and Li, Y. (2001). "A Deformation-Dependent Model for Permeability Changes in Oil Sand due to Shear Dilation." Journal of Canadian Petroleum Technology. Volume 40, Number 8.
- www.netl.doe.gov. "FIG. 1 CYCLIC STEAM INJECTION PROCESS." United States Department of Energy, Washington D.C.
- Xia, T. X., Greaves, M. (2006). "In Situ Upgrading of Athabasca Tar Sand Bitumen Using THAI." Chemical Engineering Research and Design, Volume 84, Issue 9, September 2006, page 856-864
- Yale, David P., Mayer, Todd, and Wang, Jianlin. (2010). "Geomechanics of Oil Sands under Injection." American Rock Mechanics Association 10-257.
- Yang, L. (2007). "Field Test of SAGD as Follow-Up Process to CSS in Liaohe Oil Field of China." Journal of Canadian Petroleum Technology. Volume 46, Number 4.

Yongtao, Sun, Lichang, Zhao, Liguu, Zhong, Di, and Yu, Lin. (2011). "Enhance Offshore Heavy Oil Recovery by Cyclic Steam-Gas-Chemical Co-stimulation." SPE 149831-MS.

Yuan, Yanguang, Xu, Bin, and Yang, Baohong. (2011). "Geomechanics for the Thermal Stimulation of Heavy Oil Reservoirs-Canadian Experience." SPE 150293-MS.

Zhang, X., Zhang, Y., Yue, Q., Gao, Y., and Shen, D. (2009). "Conformance Control of CSS and Steam Drive Process with a Carbamide Surfactant." Journal of Canadian Petroleum Technology. Volume 48, Number 9.



Johannes Alvarez is a PhD student at Texas A&M University in Petroleum Engineering. He holds a B.Sc. degree from Universidad Simon Bolivar, Venezuela, and a M.Sc. degree from Stanford University, USA, both in Chemical Engineering. His research interests include fracture fluid performance with surfactant additives in oil shale, enhance

oil recovery in shale formations, surface chemistry, and X-Ray tomography methods. Previously, he worked for 11 years in Petroleos de Venezuela S.A. (PDVSA) as Process and Infrastructure Engineer, Production Engineering Superintendent, Production Engineering District Manager and lately as Planning Division Manager. Mr. Alvarez is a member of the Society of Petroleum Engineers.



Sungyun Han, Goyang Gyeonggi, Republic of Korea, is a MSc student in Petroleum Engineering at Texas A&M University, College Station, Texas. He is currently researching on in-situ combustion process. His research interests include seismic interpretation and numerical modeling of thermal enhanced oil recovery. He received a B.Sc. degree of Petroleum Engineering from Texas A&M University, College Station, Texas, in 2012. He has worked as a teaching assistant in Department of Petroleum Engineering, instructing laboratory assignments of numerical methods used in oil and gas industry. He is also a research assistant in Ramey's Thermal Laboratory where he is conducting thermal EOR, In-situ combustion, experiments. Mr. Han is a member of the Society of Petroleum Engineers.